# Washington Utilities and Transportation Commission
# Intrastate Evaluation Report
# Liquid Pipeline Carrier

**HQ Operator Name:** **BP Pipelines (North America) Inc.** **Docket #** PL-030699

Pipeline Company Contact: **Pete G. Romero** Company ID# **101**

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**Pipeline Inspection Facility (Unit):**

Name: **BP Pipelines (North America)**

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**Operator Representative**

Name and Title: **Pete G. Romero, Maintenance Foreman**

**WUTC Representative**

Name and Title: **Al Jones and Kuang Chu, Pipeline Safety Engineers**

**Inspection Dates:** **September 22-26, 2003**

**Date of Last Inspection:** **July 22-25, 2002**

Amendments 195-75

## Washington Utilities and Transportation commission
## Intrastate Hazardous Liquids
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## PIPELINE SYSTEM HISTORY

1. What does the pipeline system in the maintenance district consist of: (Pipelines and pipe specifications, pump stations including pumps and horsepower, control centers, offshore facilities, pipeline subsidiaries, etc.) (*Ask for listing and obtain maps for region files*).
**Crude Oil Line: 24", 0.281"wt, API 5L grade X-52, 698 psig MOP (limited by surge pressure constraint at Terasen Pipeline Inc. (formally Trans Mountain Pipeline) with flange rating is Class 600. Pipeline was built in 1970.**

   **Butane line: 6" x 0.188"wt, API 5L Grade B, 285 psig MOP with normal operating pressure ranging from 100 to 179 psig, limited by Class 150 flange rating. Pipeline was built in 1986.**

**Pipeline Information**

2. Boundaries of Unit: (Geographical, Pipeline MP, Other)
**Crude Oil – From Terasen Pipeline scraper trap at Ferndale to BP Refinery at Cherry Point.**

   **Butane – From BP Refinery at Cherry Point to Texaco LP6 at Ferndale.**

3. Pipelines in Unit:
**Crude and Butane Pipelines.**

| Designation | MOP | Size | Miles | Commodities (C, P, HVL, $NH_3$) |
|---|---|---|---|---|
| Crude | 698 psig | 24-inch | 5 miles | Crude |
| Butane | 285 psig | 6-inch | 5 miles | Butane |
| | | | | |
| | | | | |

4. Breakout Tank Facilities: (*Number & Location*):
**No breakout tanks.**

5. Smart Pig History (*Type & Date*)
**Crude – 1995, 1997, 1999, and scheduled for 2004.**
**Butane – 1997, 2000, and scheduled for 2004.**

6. (What criterion does operator use to evaluate pig logs for excavation and determination of repair/replacement)?
**ASME B31G.**

7. High Consequence Areas identified
**<u>Yes, both pipelines.</u>**

8. Construction Data (Dates/Segment)
**<u>Crude Oil – built in 1970 and replaced 540 linear feet of 24-inch pipe near Intalco in August 2001.</u>**

**<u>Butane – built in 1986.</u>**

9. Is pre-1970 ERW pipe in the system? Is there a leak/failure history? How has the operator responded to the 1/28/1988 alert notice? (Advisory Bulletins ALN 88-01, ALN 89-01)
**<u>No.</u>**

## <u>SUBPART B – REPORTING OF ACCIDENTS & SAFETY RELATED CONDITIONS</u>

### <u>Annual Reports</u>

10. Was an annual report submitted to the Commission by April 1? (WAC 480-75-650)
**<u>Yes. See attached report.</u>**

### <u>Telephonic Notice</u>

11. Are there written procedures in the operating and maintenance manual for telephonic notice? (195.52)
**<u>Yes.</u>**

12. Did the pipeline company have any telephonic notices for this inspection period?
**<u>Yes, a leak report was call into the Commission on the butane pipeline, but later was determined to be a non-event.</u>**

13. Are there written procedures in the operations and maintenance manual for notifying the Commission and the National Response Center of a release of hazardous liquids from a pipeline resulting in any of the following: *Federal Report Incident* within 2 hours.
**<u>Yes, Section 9.</u>**

    a. Explosion or fire during the inspection period? (195.52 (a)(2))
    **<u>None.</u>**

    b. A death or personal injury necessitating an in patient hospitalization during the inspection period? (195.52 (a)(1))
    **<u>None.</u>**

    c. Any damage in excess of $25,000 (Include clean up, recovery, product loss) during the inspection period? (WAC 480-75-630 (1)(d))
    **<u>None.</u>**

d. Pollution of any water during the inspection period? (Stream, river, lake, reservoir or shoreline) (195.52 (a)(4))
**None.**

e. During the inspection period was there an event that was significant, in the judgment of the pipeline company, even though it did not meet the criteria of the above? (195.52 (a)(5))
**None.**

f. Spills of 5 gallons or more? (WAC 480-75-630 (1)(c))
**None.**

g. Results in news media coverage? (WAC 480-75-630 (1)(f))
**None.**

14. Did the operator provide notification within 24 hours of emergency situations including emergency shutdowns, material defects or physical damage that impairs serviceability? (WAC 480-75-630 (3))
**Yes. The butane pipeline was shut down until it was determined that no leak existed.**

**Accident Report**

15. Did the pipeline company submit RSPA Form 7000.1 not more than 30 days after the detection of an accident as required? (195.54)
**N/A.**

a. Explosion or fire no intentionally set by the operator; (195.50 (a))
**N/A.**

b. Release of 5 gallons or more except no report is required for a release of less than 5 bbls resulting from pipeline maintenance activity if the release is not otherwise reportable, results in water pollution, confined to company property or right-of-way and cleaned up promptly; (195.50(b))
**N/A.**

c. Death of any person; (195.50 (c))
**N/A.**

d. Personal injury necessitating hospitalization; (195.50 (d))
**N/A.**

e. Estimated property damage greater than $25,000. (195.50 (e))
**N/A.**

**<u>Safety Related Conditions</u>**

16. Does the operator have procedures for recognizing and discovery of safety-related conditions?
**<u>Yes, Section 9.3 for both crude and butane.</u>**

a. Is there a procedure for reporting safety-related conditions? (195.55) *General corrosion, pipe movement, abnormal loading caused by earthquake, flood, landslide; material defect; operator error; condition that could lead to an imminent hazard, pressure reduction 20% or more, or shutdown.*
**<u>Yes, Section 9.3 for both crude and butane.</u>**

b. Was the report filed within five (5) working days of determination within ten (10) working days of discovery?
**<u>N/A.</u>**

c. If the operator reported safety-related conditions, did they use the proper criteria?
**<u>N/A.</u>**

d. Was proper corrective action taken?
**<u>N/A.</u>**

**<u>New Construction</u>**

17. Was new construction reported to the Commission 45 days prior to construction? New construction is a new pipeline that did not previously exist or an extension of an existing line more than 100 ft. (WAC 480-75-610)
**<u>There has been no new construction since the last inspection.</u>**

**<u>Abandoned Underwater Facilities</u>**

18. Has any pipeline facility that crosses a commercially navigable waterway been abandoned? If yes, has a report been filed with the National Pipeline Mapping System? Have pre-10/10/00 abandoned navigable pipeline crossings been filed with OPS? (195.59)
**<u>N/A.</u>**

## <u>HIGHLY VOLATILE LIQUID (HVL) PIPELINE TESTING SUMMARY</u>

19. Does the operator's pipelines transport HVLs?
**<u>Yes, butane.</u>**

20. Have the HVL pipelines been pressure tested in accordance with Subpart E of Part (195.300 - 310)?
**<u>Yes, retested on 3/11/1999 to 425 psig.</u>**

a. Onshore intrastate lines in HVL service prior to 4/23/85 & constructed prior to 10/21/85.

i) 50% by 4/23/88
**N/A.**

ii) 100% by 4/23/90
**N/A.**

21. Have HVL pipelines not tested in accordance with Subpart E of Part 195 had their operating pressures reduced to:

a. 80% of the 4-hour, documented, test pressure? 195.406 (r*ecording chart or logs)*
**N/A.**

b. 80% of the 4-hour, documented, operating pressure? 195.406 (r*ecording chart or logs)*
**N/A.**

c. Required pressure reduction dates are onshore intrastate lines constructed before 10/21/85 & in HVL service before 4/23/85, must be completed by 4/23/86.
**N/A.**

## MAXIMUM OPERATING PRESSURE

22. Has the Maximum Operating Pressure (MOP) been established for each pipeline? (195.406) What is the MOP?
**Yes, Crude Oil at 698 psig MOP based on the August 2001 hydrotest, and Butane at 285 psig MOP for class 150 flanges and hydrotested on 3/11/1999.**

23. When was the pipeline constructed?
**Crude Oil in 1970 and butane 1986.**

24. How was the MOP established?
**Hydrotest.**

a. Limiting factor? What is the weakest element?
**Crude Oil – surge consideration from Terasen Pipeline and**
**Butane – Class 150 flanges.**

b. Pressure test divided by a factor of 1.25? 195.304
**Yes, crude oil pipeline was tested to 1,047 psig in August 2001 and butane pipeline was tested to 425 psig for 8 hours on 3/11/1999.**

c. What is the design pressure of the pipeline? (195.106) List SMYS, wall thickness, outside diameter, temperature factor, design factor, & seam joint factor.
**<u>Crude Oil – 779 psig; 24-inch 0.281" wt, S-52, 0.72 design factor.</u>**
**<u>Butane – 285 psig; 6-inch 0.188"wt, grade B, 0.72 design factor Temperature and seam joint derating factors for both pipeline are 1.0</u>**

25. If pressure testing was used to raise the MOP (after 9/26/02) was a report submitted to the Commission 45 days prior to the hydro test? (WAC 480-75-620)
**<u>N/A.</u>**

26. Is the MOP in compliance with 195.406?
*Except for surge pressures & other variations from normal operations, the MOP may not exceed any of the following: Design pressure (DP); DP of the weakest component; 80% of the test pressure or* components- 80% of the factory test pressure - prototype test pressure - excepted under 195.304. (195.406(a)(4))
**<u>Yes.</u>**

27. Pipeline may not be operated at a pressure that exceeds 110% of the MOP.
a. Has the operating pressure exceeded the MOP by more than 110%? (195.406(b))
**<u>No.</u>**

b. Are adequate controls and protective equipment installed to prevent the pressure from exceeding 110% of the MOP? (195.406(b))
**<u>Yes.</u>**

28. Has a surge analysis been done to ensure that surges do not exceed 110% of the MAOP? (WAC 480-75-320)
**<u>Crude Oil analysis was completed in 2001 and Butane analysis has not been completed. The pipeline is currently operated at less than 20% of SMYS.</u>**

## <u>DAMAGE PREVENTION</u>

29. Written damage prevention program available? (195.442)
**<u>Yes. Crude Oil see appendix V and for Butane pipeline see appendix VI.</u>**

30. Member of a one-call system? (RCW 19.122)
**<u>Yes.</u>**

31. Does the pipeline company advertise and use the single statewide toll-free number (1-800-424-5555) to call for locate requests (RCW 19.122.027)
**<u>Yes.</u>**

32. Does the operator have available a current list of excavators? (195.442 (c))
**<u>Both pipelines are covered in the Olympic Pipeline notification to excavators.</u>**

33. Provide notification concerning the program to the public and excavators? (195.442 (c) )
**Yes.**

34. Provide means for receiving and recording notification of pending excavations? (195.442 (c)) Does the operator respond when notified of a locate?
**Yes.**

35. Provide for markings within two business days? (RCW 19.122)
**Yes.**

36. Does the pipeline company immediately notify local first responders and the commission of any reportable release of hazardous liquids? (RCW 19.122.035 (3))
**Yes.**

37. Immediately upon receiving information of third party damage does the Pipeline Company terminate the flow of hazardous liquid in the pipeline (RCW 19.122.035 (2))
**Yes, appendix V-2**

    a. Has the pipeline company visually inspected the damaged pipeline (RCW 19.122.035 (2))
    **N/A. No damage has occurred during the past year.**

    b. Has the pipeline company determined if the damaged pipeline should be repaired or replaced (RCW 19.122.035 (2))
    **N/A.**

38. Does the operator's damage prevention program include actions to protect their facilities when directional drilling or boring operations are conducted in proximity to the facilities? (Advisory Bulletin ADB-99-04)
**Yes. Appendix V-2 the company will pot-hole their pipeline if the directional drill crosses the pipeline.**

## PUBLIC EDUCATION

39. Has the operator established a continuing education program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, or others? (195.440)
**Yes, OM&ER Book 1, Procedure #P-195.440, Part C. Contractors yearly and public every three years living on either side of the pipeline and within ½ mile of the HVL pipeline (Butane) and 1/8 mile for Crude Oil.**

    a. Conducted in English & other languages where appropriate?
    **Yes, published in English and Spanish.**

40. Have the operator and rail personnel met to discuss emergency planning issues in shared right-of-ways (Advisory Bulletin ADD-94-03)
**N/A. The pipelines cross two sets of railroad tracks and does not share a common ROW with the railroad.**

41. How does the operator implement its continuing education program?
**Once a year BP provides information packets to the surrounding neighborhoods, contractors, and public officials.**

## MAINTENANCE

### Inspection of Right-of-Way & Crossings

42. Does the operator inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 years? (195.412 (b))
**N/A.**

43. Are right-of-way inspections conducted each calendar week (unless weather impedes fly-overs if applicable) (WAC 480-75-530)
**Yes. Section 6.2 the pipeline are visually inspected bi-weekly.**

### Line Markers

44. Are line markers placed at each public road crossings, railroads crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known? (195.410(a))
**Yes. Sections 6.5 and 6.6 for crude oil and 6.7 for butane manuals.**

45. Do the line markers have the correct characteristics and information (warning, product name (including $CO_2$ if applicable), telephone number)? (195.410)(a))
**Yes. Section 6.6**

46. Are line markers maintained at waterways crossings, urban areas, and downtown business centers? Line markers are not required at crossings of waterways or heavily developed urban areas, such as downtown business areas, where (1) placement is impracticable and (2) local government maintains current substructure records. (195.410)(b))
**N/A.**

47. Are line markers placed where pipelines are aboveground in areas that are accessible to the public? (195.410(c))
**N/A.**

48. Are markers maintained at all aboveground facilities? (WAC 480-75-540)
**Yes.**

49. Are markers checked annually and replaced within 30 days? (WAC 480-75-540)
**Yes. Section 6.5 signs are maintained on an as needed basis.**

**Depth of Cover**

50. For pipelines constructed after 4/1/70, are depth of cover surveys conducted every five years or every three years for areas subject to erosion or subsoiling? (WAC 480-75-640) (This requirement becomes effective on 9/26/02)
**Typically, the existing cover is approximately 4 to 5 feet. The BP's new Compliance Requirements (Book 1) identifies depth-of cover survey at five-year intervals in Section 3 of BP's Company's Specific Requirements.**

**Valve Maintenance**

51. Does the operator maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times (195.420(a))?
**Yes, Section 6.5**

52. Does the operator inspect each mainline valve to determine that it is functioning properly at intervals not exceeding 7-1/2 months, but at least twice each calendar year? (195.420(b))
**Yes. Crude Oil – Section 6.5 and Butane – Section 6.6**

    a. Records, per 195.404(c)
    **Yes, inspected 1/02, 9/02 and 4/03.**

53. Does the operator provide protection for each valve from unauthorized operation & from vandalism? (195.420(c))
**Yes.**

54. Are valves installed at the following locations? (195.260)

    a. Suction and discharge ends of pump station.
    **Yes at the butane pipeline and there is no pump for the crude oil pipeline.**

    b. Each line entering or leaving breakout tank area.
    **There are no breakout tanks.**

    c. Along pipeline that will minimize damage or pollution from accidental discharge.
    **There are no mainline valves.**

    d. On each lateral takeoff, from the trunk line.
    **Butane line does not have lateral takeoff lives. Crude oil line has a valve on each lateral takoff. The lateral valves are located in-plant and are not jurisdictional.**

e. Each side of a water crossing that is more than 100 ft wide at high-water mark.
**N/A.**

f. On each side of reservoir holding water for human consumption.
**N/A.**

g. For quick response for environmentally sensitive areas, such as drinking water sources, national parks, etc.
**N/A.**

55. Are there any automatic or remotely controlled valves?
**No.**

**Pipe Relocation Procedures**

56. When moving any line pipe, does the operator comply with the precautions specified in 195.424, if:

a. Pressure reduction to 50% MOP for all lines. (195.424(a))
**Yes, for Crude Oil see Section 6.5 and Butane see Section 6.6 pursuant to BP Standard APL-SP-107**

b. For HVL lines joined by welding:

i. When it does not contain HVL, unless impractical; (195.424(b)(1))
**Yes, BP procedures require the pipeline to be taken out of service.**

ii. Precautions to protect public; and the use of warnings, where necessary, to evacuate the area close to the pipeline. (195.424(b)(2))
**Yes, Section 6.6 and OMER in Appendix X.**

iii. Pressure reduced to 50% MOP or lowest practical level (minimum = V.P.) 50 psig). (195.424(b)(3)(i))
**Yes, BP procedures require the pipeline to be taken out of service.**

c. For HVL lines not joined by welding. (195.424(c))
i. When it does not contain HVL, unless impractical; (195.424(c)(1))
**N/A.**

ii. Precautions to protect public; and (195.424(c)(1))
**N/A.**

iii. Line section is isolated (195.424(c)(2))
**N/A.**

57. Was a study conducted to evaluate pipe conditions during pipe movement including API 1117 stress calculations? (WAC 480-75-500)
**Yes, for projects of unusual complexity, BP use the API Recommended Practice 1117 as a guide in calculating the excavation required for moving the line. For Butane see BP's OMER - Appendix X, Paragraph H, 4, b, 2**

**Scraper & Sphere**

58. Does the operator, have a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres? (195.426)
**No, the Crude Oil launcher at Cherry Point Refinery has a relief located down stream of the launcher's mainline valve and is not protect the launcher when the valve is closed.**

59. Does he have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion?
**Yes, pressure gauges.**

## EVALUATION OF COMPUTATIONAL PIPELINE MONITORING (CPM) SYSTEMS FOR HAZARDOUS PIPELINE SYSTEM 195.134.

60. Does the operator have a leak detection system? Describe (WAC 480-75-300 (1)))
**The crude oil and butane pipelines are monitored for leaks by visually inspecting by walking the pipelines and monitoring operating pressures.**

61. Is the leak detection system capable of detecting an 8% leak within 15 minutes? (WAC 75-300 (2))
**Currently, a turbin meter is located at BP's Cherry Point facility and a mass flow meter is located at Ferndale. A new leak detection system is expected to be operational by the end of 4$^{th}$ quarter of 2004.**

62. Is there an alarm record? (WAC 480-75-300 (3))
**Yes, operator log for storage alarms.**

63. Are there leak detection maintenance records? (WAC 480-75-300 (3))
**Yes, easement inspection records are completed when product is transported.**

## COMMUNICATIONS (CONTROL CENTER)

64. Does the operator have a Supervisory Control and Data Acquisition (SCADA) system? (195.408)
**No.**

65. What date was the SCADA system installed?
**N/A.**

66. Does the operator have a communications system to provide for the transmission of information needed for the safe operation of its pipeline system? (195.408(a))
**Yes, by radio, telephone and cell phone.**

67. Is the pipeline a single-phase liquid (*without gas in liquids*) line?
**Yes.**

68. Has the operator determined that the new or replaced (installed after 7/6/99) computational pipeline monitoring SCADA system complies with API standard 1130? (195.134)
**N/A.**

69. Does the operator have the communications to monitor operational data per (195.402(c)(9)), (195.408(b))?
**Yes.**

70. Does the operator have the communications to receive notices from operator personnel, the public, & others about abnormal or emergency conditions and initiating corrective actions? (195.408 (b))
**Yes.**

71. Does the operator have two-way vocal communication between a control center & the scene of abnormal operations & emergencies? (195.408 (b))
**Yes.**

72. Does the operator have the communications with fire, police, & other appropriate public officials during emergency conditions, including a natural disaster? (195.408 (b))
**Yes.**

73. Will the communications system be affected by communication outages or SCADA failure?
**Yes.**

74. How are completed construction activities, such as facility modifications, communicated to the controller?
**At the refinery the project manager is responsible for the Crude Oil and Butane pipelines: The following activities include:**
- **System setup for daily communication.**
- **Training is done prior to implementing any change.**
- **Management of Change is in place.**

75. Are all the unattended locations on the operator's system which control the receipt and delivery of hazardous liquids monitored? (195.402 (c) (9))
**N/A. The system is manned at all locations.**

76. Can unattended facilities be controlled from a central location? (195.402(c) (9))
**N/A.**

77. Does the operator review the capacity, configuration and operating parameters of the SCADA system? How are system modifications evaluated? (Advisory Bulletin ADB-99-03)
**N/A.**

## CORROSION CONTROL

78. Does the Operator require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance. (195.555)
**Yes.**

79. Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is: (195.557)
    a. Constructed, relocated, replaced, or otherwise changed after the applicable dates:

        i. 3/31/70 – interstate pipelines excluding low stress.
        **N/A.**

        ii. 7/31/77 – interstate offshore gathering excluding low stress.
        **N/A.**

        iii. 10/20/85 – intrastate pipeline excluding low stress.
        **N/A.**

        iv. 7/11/91 – carbon dioxide pipelines.
        **N/A.**

        v. 8/10/94 – low stress pipelines.
        **N/A.**

    *NOTE: This does not include the movement of pipe under 195.424.*

80. Coating material for external corrosion control must; (195.559)

    a. Be designed to mitigate corrosion of the buried or submerged pipeline;
    **Yes, the pipeline coating information is in Section 2.4 of each pipeline manuals. The Crude Oil was originally coated with cold tar and approximately 6,500 LF was replaced with polyethylene coated pipe. The butane pipeline is coated with a cold tar wrap. (Section 2.4 pg 5)**

b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
**<u>Yes.</u>**

c. Be sufficiently ductile to resist cracking;
**<u>Yes.</u>**

d. Have enough strength to resist damage due to handling and soil stress;
**<u>Yes.</u>**

e. Support any supplemental cathodic protection; and
**<u>Yes.</u>**

f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.
**<u>Yes.</u>**

81. All external pipe coatings required under 195.557 must be inspected just prior to lowering the pipe in the ditch or submerging the pipe. (195.561(a))
**<u>Yes, pursuant to Section 6.5 all exposed pipe visually or holiday detector inspected for gaps, cracks, or voids. Engineering Specification SP 101 for new pipe and field applied coating.</u>**

82. All coating damage discovered must be repaired. (195.561(b))
**<u>Yes, OM&ER Book 1, Procedure #P-195.551, Part D, Section 2</u>**

83. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in 195.557 (a) within one (1) year? (195.563)
**<u>Yes.</u>**

84. Each buried or submerged pipeline converted under 195.5 must have cathodic protection if the pipeline: (195.563)

a. Has cathodic protection that substantially meets 195.571 before the pipeline is placed in service, or
**<u>N/A.</u>**

b. Is a segment that is relocated, replaced, or substantially altered?
**<u>Yes.</u>**

85. All other buried or submerged pipelines that have an effective external coating must have cathodic protection. (195.563)
**<u>Yes.</u>**

86. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections. (195.563)
**N/A.**

87. Unprotected pipe must have cathodic protection if required by 195.573 (b). (195.563)
**N/A.**

88. Test leads installation and maintenance. (195.567)
**Yes, OM&ER Book 1, Procedure #P-195.551 Part G, Section 2**

89. Are there test stations at casing? (WAC 480-75-340)
**Yes.**

90. Examination of Exposed Portions of Buried Pipelines. (195.569)
**Yes, Section 6.5**

91. Is the pipe examined prior to backfilling? (WAC 480-75-520)
**Yes.**

92. Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96 (incorporated by reference). (195.571)
**Yes, BP reference API RP 651, Section 9, and NACE RP 0169**

93. Pipe to soil monitoring (annually/15 months). Separately protected short sections of bare ineffectively coated pipelines (every 3 years not to exceed 39 months). (195.573)
**Crude Oil – Yes, Section 6.3**
**Butane – Yes, Section 6.4**

94. Before 12/29/2003 or not more than 2 years after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraphs 10.1.1.3 of NACE RP0169-96. (195.573)
**N/A.**

95. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows: (195.573)
    a. Determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment.
    **N/A.**

    b. Before 12/29/2003 – at least once every 5 years not to exceed 63 months.
    **N/A.**

c. Beginning 12/29/2003 – at least once every 3 years not to exceed 39 months.
**N/A.**

96. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection – at least 6 times each year, intervals not to exceed 2 ½ months. (195.573)
**Yes.**

97. Any deficiencies identified in corrosion control must be corrected as required by 195.401(b). (195.573)
**Yes.**

98. Is remediation of corrosion system deficiencies initiated within 90 days of discovery? (WAC 480-75-510)
**Yes.**

99. Are there adequate provisions for electrical isolations? (195.575)
**Yes.**

100. Are electrical isolation points inspected and tested? (195.575 (c))
**Yes.**

101. Are pipelines located in close proximity to electrical transmission tower footings, ground cables, counter poise or other areas where it is reasonable to foresee fault currents or unusual risk of lightning protected from fault current or lightning? (195.575 (e))
**Yes, the Butane pipeline is located in close proximity to Intalco and is covered in Section 6.4**

102. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects? (195.577)
**Yes.**

103. Design & install CP systems to minimize effects on adjacent metallic structures. (195.577)
**Yes.**

104. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken? (195.579)
**Internal corrosion has been observed in either pipeline. The crude oil pipeline has low water content.**

105. Internal Corrosion – Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion. Coupons or other monitoring equipment must be examined at least 2 times each year, not to exceed 7 ½ months. (195.579)
**N/A.**

106. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe? What steps are taken to minimize internal corrosion? (195.579)
**Yes, Section 6.4**

107. Are pipelines protected against atmospheric corrosion using required coating material? (See exception to this statement). (195.581)
**Yes.**

108. Atmospheric corrosion monitoring – (195.583)

a. ONSHORE – At least once every 3 years but at intervals not exceeding 39 months.
**Yes, Section 6.5 paint coatings are maintained as needed.**

b. OFFSHORE – At least once each year, but at intervals not exceeding 15 months.
**N/A.**

109. Are procedures in place and are they followed to either reduce the MOP, or repair/replace pipe if general corrosion has reduced the wall thickness? (195.585)
**Yes, Section 6.4**

110. Are procedures in place and are they followed to either reduce the MOP, or repair/replace if localized corrosion has reduced the wall thickness? (195.585).
**Yes, Section 6.4**

111. Are applicable methods used in determining the strength of corroded pipe (ASME B-31G, RSTRENG) (195.587)
**Yes.**

112. Are aboveground breakout tanks with cathodic protection inspected in accordance with API 651, unless the operator notes why compliance with certain provisions of API 651 are not necessary? (195.416 (j))
**N/A.**

113. Corrosion Control Records Retention (Some are required for 5 years; some are for the service life. (195.589)
**Yes.**

## PUMPS & BREAKOUT TANKS

### Fire Fighting Equipment

114. Does the operator maintain adequate firefighting equipment at each pump station & breakout tank area? (195.430)
**Yes, at pump station. There are no breakout tanks at BP facility.**

115. The equipment must be:

a. In proper operating condition at all times. (195.430(a))
**Yes.**

b. Plainly marked so that its identity as firefighting equipment is clear. (195.430(b))
**Yes.**

c. Located so that it is easily accessible during a fire. (195.430(c))
**Yes.**

## PUMPS STATION

### Alarms

116. Has operator installed warning devices in pump station buildings to warm of the presence of hazardous vapors? (195.262)
**N/A.**

117. Does the operator maintain daily operating records which indicates the discharge pressures at each pump station for a period of 3 years? (195.404(b))
**Yes.**

## OVER PRESSURE SAFETY DEVICES

118. Does the operator inspect and test each pressure limiting device, relief valve, pressure regulator, or other pressure control equipment determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable? (195.428(a))
**There are no pressure relief valves for both lines. Thermal relief valves are located at the butane pig launcher and the crude oil pig receiver. Both thermal relief valves have are inspected and tested annually.**

119. Does the operator inspect & test over pressure safety devices at the following intervals?

a. Non-HVL pipelines: once each calendar year, within 15 month intervals. (195.428(a))
**BP Cherry Point Refinery's pressure is limited by its pump's discharge pressure and ConocoPhillips and Terasen have over pressure safety devices when transporting crude oil to BP Cherry Point Refinery.**

b. HVL pipelines: twice each calendar year, with 7.5 month intervals. (195.428(a))
**BP Cherry Point Refinery's pressure is limited by its pump's discharge pressure also, the pig launcher has a thermo relief device.**

c. Relief valves on HVL breakout tanks within 5 year intervals. (195.428(b))
**N/A.**

d. Records, per (195.404(c))
**BP Cherry Point Refinery's pressure is limited by the design of the pump's discharge pressure. Additional design information is needed from the ConocoPhillips and Terasen facilities when transporting product to BP Cherry Point Refinery.**

120. Are pressure relief devices set at or below MOP? (WAC 480-75-320)
**BP Cherry Point Refinery's pressure is limited by its pump's discharge pressure.**

## BREAKOUT TANKS

121. Has the operator correctly identified/classified it's tanks?
**N/A.**

122. Does the operator inspect each breakout tank (atmospheric and pressured) each calendar year, (195.432)

a. Within 15 month intervals?
**N/A.**

123. Records, per (195.404 (c))
**N/A.**

## TANK INSPECTION SURVEY (195.432 (b))

124. In the case of relief valves on pressure breakout tanks containing highly volatile liquids, is each valve tested within 5 years?
**N/A.**

125. Are tanks externally inspected monthly? (195.432 (b))
**N/A.**

126. Are corrosion rates established for the tank bottoms? (195.432 (b))
**N/A.**

127. Is API 653 section 4 used for inspecting storage tanks?
**N/A.**

128. Has the tank shell been inspected in accordance with 4.3.3 of API 653?
**N/A.**

129. Are tanks built in accordance with API 2510 (Design and Construction of LPG Systems) inspected according to Section 6 of API 510? (195.432 (c))
**N/A.**

130. Are tanks constructed in accordance with API 650 or Standard 12C repaired in accordance with API 653? (195.205 (b)(1)
**N/A.**

131. Are tanks constructed in accordance with API 620 or standard 12F repaired in accordance with those standards? (195.205 (b)(2))
**N/A.**

132. Are high-pressure tanks built in accordance with API 2510 repaired in accordance with API 510? (195.205 (b)(3))
**N/A.**

133. Does the operator provide protection against ignition from static charge, lightning and stray currents during operations and maintenance activities involving breakout tanks in accordance with API 2003 unless the operator describes why compliance with this standard is not necessary? (195.405 (a))
**N/A.**

134. Has the operator reviewed and considered the potentially hazardous conditions, safety practices and procedures in API 2026 (Safe Access/Egress Involving Floating Roofs of Storage Tanks) for inclusion in the Operations Manual? (195.416 (j))
**N/A.**

135. Do breakout tanks constructed or altered after 10/2/00 have overfill protection systems in accordance with section 5.1.2 of API 2510 (Design and Construction of LPG Installations) or API 2350 (Overfill protection for Storage Tanks in Petroleum Facilities)? If no, does the operator note in the Operations Manual why compliance with that part is not necessary? (195.428 (c))
**N/A.**

136. Are overfill protection systems inspected and tested annually? Inspected two times/year and tested every five years for highly volatile liquids? (195.428 (d))
**N/A.**

137. Are breakout tanks constructed with liners after 10/2/2000 installed in accordance with API 652 or does the operator note why API 652 is not necessary for tank safety? (195.579 (d))
**N/A.**

138. Do breakout tanks have independent level alarms? (WAC 480-75-330)
**N/A.**

## SIGNS

139. Does the operator maintain signs visible to the public around each pumping station & breakout tank area? (195.434)
**Yes, OM&ER Book 1, Procedure #P-195.442 Part D.**

140. Do the signs contain the name of the operator and an emergency telephone number? (195.434)
**Yes.**

## SECURITY OF FACILITIES PROCEDURES

141. Does the operator provide protection for each pumping station and breakout tank area & other exposed facilities from vandalism & unauthorized entry? (195.436)
**Yes, the facility is enclosed with a security fence.**

## SMOKING OR OPEN FLAMES

142. Does the operator prohibit smoking & open flames in each pump station & breakout tank area where there is the possibility for the presence of hazardous liquids or flammable vapors? (195.438)
**Yes.**

## PIPELINE REPAIRS

143. Does the operator, in repairing its pipeline systems, insure that the repairs are made in a safe manner & are made so as to prevent damage to persons or property? (195.422)
**Yes, Section 6 with reference to API and ASME.**

144. Are repairs made in accordance with ASME B31.4? (WAC 480-75-440)
**Yes, Section 6 with reference to API and ASME.**

## MAPS & RECORDS

Each operator shall maintain current maps & records of its pipeline systems that include at least the following information: (195.404(a))

145. Location & identification of the following facilities:

    a. Breakout tanks
    **N/A.**

    b. Pump stations
    **Yes.**

c. Scraper & sphere facilities
**Yes.**

d. Pipeline valves
**N/A, there are no mainline valves.**

e. Rights-of-way
**Yes.**

146. Cathodically protected pipelines. (195.589)

a. Galvanic anodes
**Yes.**

b. Neighboring structures bonded to CP system
**Yes.**

c. # Anodes, how installed and spacing
**Yes.**

147. All crossings of public roads, railroads, rivers, buried utilities, & foreign pipelines.
**Yes.**

148. The maximum operating pressure of each pipeline?
**Yes.**

149. The diameter, grade, type, & nominal wall thickness of each pipe.
**Yes.**

150. Was the MOP breached? (195.406)
**No.**

151. Does the operator maintain daily operating records that indicate any emergency or abnormal operation to which the procedures of 195.404 (b) apply for a period of 3 years?
**Yes, at the Blender Operator Control Center.**

152. Does the operator maintain the following records for the periods specified? (195.404(c))

a. The date, location, & description of each repair made on pipe maintained for life?
**Yes.**

b. The date, location, & description of each repair, other than pipe, maintained for at least 1 year.
**Yes, OM & ER Book 1, #P-195.404**

c. Each inspection & test required by this Subpart F maintained for at least 2 years, or until the next inspection or test is performed, whichever is longer?
**<u>Yes.</u>**

d. How does the operator control engineering drawing revision, review, approval, and distribution?
**<u>Engineering Group procedure, Engineering Spec 211 "Diagram Policy and Procedures".</u>**

e. Do operator's as-built drawings agree with the field?
**<u>Yes.</u>**

f. Do SCADA terminals get updates?
**<u>N/A.</u>**

g. Do facility process control and flow schematics adequately indicate in-place facilities and operation?
**<u>Yes, in Control Flow Schematics.</u>**

153. Are maps updated within 6 months? (WAC 480-750-600)
**<u>Yes and as needed.</u>**

## <u>SUBPART E – HYDROSTATIC TESTING</u>

154. Does the operator hydrostatically test each new pipeline system, each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced? (195.302 (a))
**<u>Yes, OM & ER Book 1, Procedure #P-195.300</u>**

155. Have HVL lines been tested per the requirements of this section? (195.302(b)
**<u>N/A.</u>**

156. Does the operator test its pipelines to the correct pressure & for the correct duration? (195.302(c))
**<u>Yes, OM & ER Book 1, Procedure #P-195.300, Part G.</u>**

157. Does the operator, hydrostatically test under 195.305 all pipe and all attached fittings, including components, unless otherwise permitted by (195.305(b))
**<u>Yes.</u>**

158. Is water used as the test medium, except as allowed? (195.306)
**<u>Yes.</u>**

159. Does the operator, hydrostatically test, pipe associated with tie-ins, either with the section to be tied in or separately? (195.308)
**Yes, tie-in weld are x-rayed and the tied in section is hydrostatically tested separately.**

160. Does the operator maintain a record of each hydrostatic test required by this Subpart - record of the latest test must be retained? (195.310(a))
**Yes, OM & ER Book 1, Procedure #P-195.300, Part L.**

161. Does the record required by paragraph (a) of this Section include (195.310(b)):

a. Pressure recording charts
**Yes.**

b. Test instrument calibration data.
**Yes.**

c. Name of operator -person responsible - Test Company used, if any.
**Yes.**

d. Date and time of the test.
**Yes.**

e. Minimum test pressure.
**Yes.**

f. Test medium.
**Yes.**

g. Description of facility tested and test apparatus.
**Yes.**

h. Explanation of any pressure discontinuities - test failures - that appear on the pressure recording chart.
**Yes.**

i. Where elevation differences in test section exceed 100 feet - a profile - elevation over entire length of test section.
**Yes.**

j. Signature of certifying agent. (WAC 480-75-420 (4)(b)
**Yes.**

k. Beginning and ending times of the test. (WAC 480-75-420 (4)(c))
**Yes.**

l. Beginning and ending temperatures. (WAC 480-75-420 (4)(d))
**Yes.**

m. Highest and lowest pressure achieved. (WAC 480-75-420 (4)(e))
**Yes.**

## SUBPART D - WELDING

The compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by 195.222, as well as (195.200)

162. Is welding performed by welders who have been qualified in accordance with section 3 of the API Standard 1104 or Section IX of the ASME Boiler & Pressure Vessel Code, except that a welder qualified under an earlier edition that listed in 195.3 may weld, but may not re-qualify under that earlier edition? (195.214)
**Yes, OM & R Book 1, Procedure #P-195.214, Part C, 2 and Engineering Specification SP 004**

163. A miter joint is not permitted. (195.216)
**Correct, OM & ER Book 1, Procedure #P-195.214, Part J.**

**Records of Welders Qualification**

164. Is the welding performed in accordance with welding procedures qualified to produce welds meeting the requirements of API 1104, Section 6 or ASME Section IX?
**Yes.**

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In the welding of repair sleeves and fittings, do the operator's procedures give consideration to:

a. The use of low hydrogen welding rod
**Yes.**

b. Cooling rate of the weld
**Yes.**

b. Metallurgy of the materials welding (weldability carbon equivalent)
**Yes, OM & ER Book 1, Procedure #P-195.214, Part C.**

c. Proper support of the pipe in the ditch
**Yes.**

165. Is each welding procedure recorded in detail (195.214(b))
**Yes, OM & ER Book 1, Procedure #P-195.214, Part C.**

166. Are welding procedures qualified in accordance with a standard that is accepted by the industry - API 1104; ASME Boiler & Pressure Vessel Code; Other
**Yes.**

167. Has the quality of the test welds to qualify the procedures been determined by destructive testing? (195.214(a))
**Yes.**

168. Are detailed results of the procedure qualification tests recorded & retained? (195.214(b))
**Yes.**

**Welding: ARC Burns**

169. Does the operator require the repair or replacement of arc burns? (195.226(a))
**Yes, OM & ER Book 1, Procedure #P-195.214, I**.

170. Does the operator require verification of the removal of the metallurgical notch by nondestructive testing? (Ammonium persulfate) (195.226(b))
**Yes.**

171. When pipe is being welded, is ground wire attached to the pipe by other means than welding? (195.226(c))
**Yes.**

**Welds: Acceptability & Non-Destructive Testing**

172. Does the operator nondestructively test welds to insure their acceptability according to Section 6 of API 1104 & per the requirements of 195.234 in regard to the number of welds to be tested? (195.228)
**Yes, OM & ER Book 1, Procedure #P-195.214, Part M and #P-195.234**

173. Is nondestructive testing of welds performed: (195.234(b))

a. In accordance with written procedures for NDT.
**Yes.**

b. By qualified personnel.
**Yes.**

174. Does the operator maintain records of the total number of girth welds & the number nondestructively tested, including the number rejected & the disposition of each rejected weld? (195.266)
**Yes, OM & ER Book 1, Procedure #P-195.234, Part J.**

**Welds: Repair or Removal of Defects**

175. Does the operator remove and/or repair welds that are unacceptable in accordance with the requirements of (195.230)?
**Yes, OM & ER Book 1, Procedure #P-195.234, Part G.**

## TRAINING PROCEDURES (CONTROL CENTER & FIELD)

Each operator shall establish and conduct a written continuing training program to instruct emergency personnel to (195.403(a)),

176. Has operator established and conducted a continuing training program to instruct operating and maintenance personnel?
**Yes, OM & ER Book 1, Procedure #P-195.403, Part B.**

177. Does program address 195.403?
**Yes.**

    a. Carry out the operating, maintenance, emergency, response procedures established under 195.402? (195.403(a)(1))
    **Yes.**

    b. Know the characteristics and hazards of the liquids or carbon dioxide, including HVLs? - flammability, odorless vapors, water reactions? (195.403(a)(2))
    **Yes.**

    c. Recognize conditions that are likely to cause emergencies, predict the consequences of malfunction or failures - take appropriate actions? (195.403(a)(3))
    **Yes.**

    d. Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide - to minimize the potential for fire, explosion, toxicity, or environmental damage? (195.403(a)(4))
    **Yes.**

    e. Learn the proper use of firefighting procedures & equipment - fire suits, breathing apparatus, etc? (195.403(a)(5))
    **Yes.**

178. Does the operator require and verify that its supervisors maintain a thorough knowledge of the procedures they are responsible for? (195.403(c))
**Yes, OM & ER Book 1, Procedure #P-195.403, supervisor shall review all sections of the Operating Maintenance, and Emergency Response Book I, II, and Contingency Plan Manuals.**

179. Does the operator have a written qualification program? Does the program include: (195.505)

a. Identification of qualified tasks? (195.505(a))
**BP has adopted the BP Pipeline Company's qualification program, which is designed to ensure that all individuals working on regulated pipeline facilities are qualified to perform the specific covered tasks and to reduce the probability and consequences of incidents or accidents.**
**Crude Oil and Butane - Section 10.5 and includes 39 covered tasks.**

b. An evaluation that individuals performing covered tasks are qualified? (195.505(b))
**Yes, in BP's Operator Qualification (OQ) Program, Section 4.**

c. Individuals not qualified are directed and observed by qualified individual? (195.505(c))
**Yes, Section 10.5 and BP's OQ Program, Section 4.**

d. Evaluating individuals if there is reason to believe that the individual's performance of a covered task contributed to an accident? (195.505(e))
**Yes, BP's OQ Program, Section 4.**

e. Evaluating individuals if the operator has reason to believe that the individual is no longer qualified to perform the covered task? (195.505(e))
**Yes.**

f. Communicating changes that affect covered tasks to individuals performing those tasks? (195.505(f))
**Yes.**

g. Identifying covered tasks and intervals at which the evaluation of the individual's qualifications are needed? (195.505(g))
**Yes.**

180. Do qualification records include: (195.507(a))

a. Identification of qualified individuals? (195.507(a)(1))
**Yes, BP's Pipeline Business Unit's Management of Change keeps all qualified individuals informed of their status and covered task changes.**

b. Identification of the covered tasks the individual is qualified to perform? (195.507(a)(2))
**<u>Yes, BP's OQ Program Manual, Chapter 6.</u>**

c. Dates of current qualifications? (195.507(a)(3))
**<u>Yes.</u>**

d. Qualification methods? (195.507(a)(4)
**<u>Yes.</u>**

181. Are records that support the individual qualifications maintained while the individual is performing the covered task? Are records of prior qualification and records of individuals no longer performing covered tasks retained for five years?
**<u>Yes, BP's Pipeline Business Unit's Management of Change keeps all qualified individuals informed of their status and covered task changes.</u>**
**<u>BP's OQ Program Manual, chapter 7.</u>**

## <u>OPERATION & MAINTENANCE PROCEDURES</u>

182. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies? General (195.402(a))
**<u>Yes, OM & ER Book 1, Procedure #P-195.402</u>**

183. Does the operator review the manual at intervals not exceeding 15 months, but at least each calendar year?
**<u>Yes.</u>**

184. Are the manuals available, as required?
**<u>Yes.</u>**

185. Are the procedural manuals adequate? Amendments Date________(195.402(b))
**<u>Yes, Procedural manuals are in transmission from Cherry Point Refinery to BP Pipeline.</u>**

186. Are amendments identified on a log sheet? (WAC 480-75-660(2))
**<u>The new manuals will include the log sheet.</u>**

*Written procedures must be <u>followed</u> to provide safety during maintenance and normal operations.*

### <u>Normal Operation</u>

187. Does the operator have procedures for (195.402(c)):

a. Making construction records, maps, & operating history available as necessary for safe operation & maintenance? (195.402(c))
**<u>Yes, OM & ER Book 1, Procedure #P-195.402(c)</u>**

b. Analyzing pipeline accidents to determine their causes? (195.402(c)(5))
**<u>Yes</u>**.

c. Minimizing the potential for hazards identified in areas requiring immediate response (195.402(c)(4)) and minimizing the possibility of recurrence of accidents analyzed. (192.402(c)(5))
**<u>Yes</u>**.

d. Operating, maintaining and repairing the pipeline system in accordance with each of the requirements of subpart H-Corrosion Control. (195.402(c)(3).
**<u>Yes.</u>**

e Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within the limits prescribed by 195.406, considering the hazardous liquid or carbon dioxide in transportation, variations in altitude along the pipeline, and pressure monitoring and control devices? (195.402(c)(7))
**<u>Yes.</u>**

f. In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by 195.406? (195.402(c)(8))
**<u>The pipelines are designed to fail safe because the design pressure will never be achieved by the pumping equipment.</u>**

g In the case of facilities not equipped to fail safe that are identified under 195.402(c)(4) or that control receipt and delivery of the hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location? (195.402 (c)(9))
**<u>Both pipelines are designed to fail safe and the control room monitor pressure, temperature, and flow rates.</u>**

h. Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards? (195.402(c)(10)
**<u>Yes, OM & ER Book 1, Procedure #P-195.402(c)(10)</u>**

i. Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases?
**Yes.**

j. Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resource of each hazardous liquid pipeline emergency and acquaint the officials with the operator's ability in responding to a hazardous liquid pipeline emergency and means of communication? (195.402(c)(12))
*In complying with 195.402(c)(12), operators must meet face-to-face with public officials and maintain an ongoing face-to-face liaison after the initial meeting.*
**Yes, handled through the Refinery Safety Department.**

k. Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found? (195.402(c)(13))
**Yes, "annually each supervisor should review work performed by the operations personnel reporting to him" pursuant to OM&ER Book 1, Procedure #P-195.402(c)(13)**

l. Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavations, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line? (195.402(c)(14))
**Yes.**

m. Providing leak detection under flow and no flow conditions and including a procedure for responding to alarm. (WAC 480-75-300)
**Yes.**

n. Responding to breakout tank overfill alarms. (WAC 480-75-330)
**N/A.**

o. Backfilling pipe. (WAC-75-400)
**N/A.**

p. Using a holiday detector to check coating condition prior to backfilling. (WAC-75-410)
**Yes.**

q. Hydrostatic testing of pipe. (WAC 480-75-420)
**Yes.**

r. Repairing pipe in accordance with ASME B31.4. (WAC 480-75-440)
**Yes.**

s. 100% Inspection of welds. (WAC 480-75-460)
**Yes.**

t. Remedial action for corrosion deficiencies. (WAC 480-75-510)
**Yes.**

u. Inspecting the pipe prior to backfill. (WAC 480-75-520)
**Yes.**

v. Providing weekly right-of-way inspections. (WAC 480-75-530)
**Yes.**

w. Marking aboveground facilities. (WAC 480-75-540)
**Yes.**

x. Reviewing change in class location for pipelines installed after 9/26/2003. (WAC 480-75-550)
**Yes.**

y. Maintaining maps, drawings and records. (WAC 480-75-600)
**Yes.**

z. Reporting proposed construction to WUTC for new construction. (WAC 480-75-610)
**Yes.**

aa. Providing notice to WUTC of hydrotest to change MOP. (WAC 480-75-620)
**Yes.**

bb. Reporting emergency situations including emergency shutdowns, material defects or physical damage that impairs serviceability within 24 hours to WUTC. (WAC 480-75-630)
**Yes.**

cc. Providing depth of cover surveys. (WAC 480-75-640)
**See Question #50 (above).**

dd. Providing a schedule of inspection and testing for mechanical and electrical components within the pipeline system. (WAC 480-75-660)
**The scheduling will be in Book I and in the CMMS Computerized Maintenance Management System.**

ee. Describing the process for ensuring structural integrity of the pipeline by in-line inspections, hydro testing or other appropriate technique. (WAC 480-75-660)
**Integrity Management.**

ff. Describing failsafe systems including emergency shutdown and isolation procedures. (WAC 480-75-660)
**<u>Isolation Procedures are in Book II for Abnormal and Emergency Procedures.</u>**

gg. Describing emergency management training for operators. (WAC 480-75-660)
**<u>Procedure #P-195.403 Part B – Training.</u>**

hh. Responding to earthquakes including threshold for line shutoff and restart procedures. (WAC 480-75-660)
**<u>Book II for "Emergency Response Procedures"</u>**

ii. Assessing impacts on the pipeline system due to landslides. (WAC 480-75-660)
**<u>N/A.</u>**

jj. Responding to floods. (Advisory Bulletin ADB-93-03)
**<u>Book II for "Emergency Response Procedures"</u>**

**<u>Abnormal Operating Procedures</u>**

*Written procedures must be <u>followed</u> to provide safety when operating design limits have been exceeded. (195.402(d))*

188. Does the operator have procedures for:

a. Responding to, investigating and correcting the cause of:

i. Unintended closure of valves?
**<u>Yes, OM & ER Book 1, Procedure #P-195.402(d) Part B</u>**

ii. Unintended shutdowns?
**<u>Yes.</u>**

iii. A flow rate outside normal operating limits?
**<u>Yes.</u>**

iv. Loss of communications?
**<u>Yes.</u>**

v. The operation of any safety device?
**<u>Yes.</u>**

vi. Any other malfunction of a component?
**<u>Yes.</u>**

vii. Any deviation from normal operation?
**<u>Yes.</u>**

viii. Any personnel error?
**<u>Yes.</u>**

b. Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operation? (195.402(d)(2))
**<u>Yes, OM & ER Book 1, Procedure #P-195.402(d) Part C</u>**

c. Correcting variations from normal operation of pressure and flow equipment and controls? (195.402(d)(3))
**<u>Yes.</u>**

d. The operating personnel to notify responsible operator personnel when notice of an abnormal operation is received? (195.402(d)(4))
**<u>Yes.</u>**

e. Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found? (195.402(d)(5))
**<u>Yes, OM & ER Book 1, Procedure #P-195.402(c)13 & #P-195.403 for Training.</u>**

189. What recent events have occurred where a line segment experienced an abnormal operation in which the line pressure exceeded normal operating pressure? Did the safety devices function properly?
**<u>N/A.</u>**

## <u>EMERGENCY PROCEDURES</u>

190. Does the operator have and conduct a continuing education program that instruct emergency personnel to:

a. Carry out emergency procedures established under 195.402? (195.403(a)(1))
**<u>Yes, OM & ER Book 1, Procedure #P-195.403, Part B</u>**

b. Know the characteristics and hazards of the hazardous liquids transported? (195.403(a)(2))
**<u>Yes.</u>**

c. Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and take appropriate action? (195.403(a)(3))
**<u>Yes.</u>**

d. Take steps necessary to control accidental release of hazardous liquid and to minimize the potential for fire, explosion, toxicity or environmental damage? (195.4039a)(4))
**Yes.**

e. Learn the proper use of firefighting procedures and equipment, fire suits and breathing apparatus by utilizing a simulated pipeline emergency situation? (195.403(a)(5))
**Yes.**

191. At intervals not exceeding 15 months but within each calendar year, did the operator:

a. Review with personnel their performance in meeting the objectives of the emergency response training program? (195.403(b)(1))
**Yes, OM & ER Book 1, Procedure #P-195.403 Training.**

b. Make appropriate changes to the emergency response training program to ensure that the program is effective? (195.403(b)(2))
**Yes, OM & ER Book 1, Procedure #P-195.403 Training.**

192. Does the operator require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible for ensuring compliance? (195.403(c))
**Yes, OM & ER Book 1, Procedure #P-195.403 Training.**

## FIELD REVIEW OF PIPELINE

193. Pumping Stations (195.262)
**Pumping stations are provided by BP Cherry Point Refinery, ConocoPhillips and Terasen facilities.**

194. Station Safety Devices (195.262)
**Safety devices include pressure, temperature, and flow gauges.**

195. Pre-Pressure Tested Pipe-Marking & Inventory (195.308-12)
**Inventory is maintained by the refinery.**

196. Knowledge of Operating Personnel (195.403)
**The operator is knowledgeable in pipeline safety, experienced in pipeline operation, and good understand of the pipeline's cathodic protection systems.**

197. ROW Markers (195.410)
**Pipeline has good aboveground markers**.

198. River Crossing (195.412)
**N/A.**

199. Cathodic Protection (195.414)
**The pipelines have a complex cathodic protection system in-place including two rectifiers, mag-anodes, and anode flex ribbons.**

200. Pipeline Components Exposed to the Atmosphere (195.416)
**Aboveground piping has good coating except at the Cherry Point Refinery pig launcher and receiver where atmospheric corrosion exists at flange connections, fasteners, saddle reinforcement, and where the exterior pipe coating is damaged.**

201. Rectifiers (195.416)
**Adequate, except the rectifier near the Cherry Point Refinery is indicating that the ground bed is nearing its expected life.**

202. Valve Maintenance (195.420)
**Good.**

203. Valve Protection from Unauthorized Operation & Vandalism (195.420)
**Good, valves are within a locked security fenced area with a locking device at all DOT valves.**

204. Scraper & Sphere Facilities & Launchers (195.426)
**Good, except the 6-inch diameter butane pig launcher at the Cherry Point Refinery was equipped with a sun relief valve located downstream from the launcher's mainline valve. The valve was placed in the wrong location and needs to be located on the launcher side of the mainline valve.**

205. Pressure Limiting Devices (195.428)
**N/A.**

206. Relief Valves - Location - Pressure Setting - Maintenance (195.428)
**Pump discharge pressures are less than the MOP.**

207. Pressure Controllers (195.428)
**Limited by pump discharge pressures.**

208. Fire Fighting Equipment (195.430)
**Current to code.**

209. Breakout Tanks (195.432)
**N/A.**

210. Signs - Pumping Station - Breakout Tanks (195.434)
**Posted and good condition.**

211. Security - Pumping Stations - Tanks (195.436)
**Good security at all facilities.**

212. No Smoking Signs (195.438)
**Posted and good condition.**